

Grid Impacts of Electric Vehicles and Managed Charging in California

Linking Agent-Based Electric Vehicle Charging with Power System Dispatch Models

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Abstract

Deep changes are occurring in both the transportation and electricity sectors with the adoption of plug-in electric vehicles (PEVs) and the addition of renewable energy (RE) resources to the generation mix. We use California as a case study to examine the synergies of these two energy transitions, by evaluating the economic value and RE grid integration impacts of different penetration levels of PEVs (ranging from 0.95 million to 5 million PEVs) under various charging strategies. We consider the effects of smart charging and time-of-use (TOU) charging, under a State mandate requiring that utilities produce at least 50% of electricity from renewable sources by 2025. Previous studies that have evaluated such managed PEV charging strategies have shown them to help integrate RE into power grids but have not demonstrated feasibility by fully representing constraints imposed by the mobility requirements and charging choices of PEV drivers. We fill this gap by linking high-resolution travel behavior and grid production cost models that more accurately characterize charging infrastructure, travel demand, and grid dispatch constraints. We find that the flexibility inherent in PEV smart charging patterns can provide substantial benefits to the power sector, primarily in lowering grid operating cost and the amount of RE that must be curtailed (turned down or off from the level that they would otherwise be producing) to avoid over-generation when supply and demand are mismatched. For example, if treated as flexible loads, 2.5 million smart charging PEVs avoid about 50% of incremental system operating costs annually and reduce renewable energy curtailment by about 30% annually relative to when the same number of unmanaged charging PEVs are added to the grid. Overnight TOU charging provides similar cost savings, though not curtailment reductions, without incurring smart charging implementation costs. Both smart and overnight TOU charging can defer system infrastructure expansion at PEV deployment of 5M, which is the State's goal for 2030.

Executive Summary

Increasing the level of renewable energy (RE) in the power system, in parallel with transportation electrification, opens up synergistic opportunities to decrease costs to rate payers and to vehicle owners through resource coordination. In this report¹ we analyze these opportunities using detailed simulation modeling and a California case study with national implications. We focus on California because the state already has 500,000 plug-in electric vehicles (PEVs)—about half of all in the United States—and has a goal of reaching 1.5 million Zero Emission Vehicles, by 2025. In addition, California is pursuing a RE-dominant generation portfolio with a mandate that more than 50% of the state's electricity consumption come from renewable sources.

This significant addition of PEVs to the California electric grid could either exacerbate or help with the integration of more RE, depending on whether charging is unmanaged (i.e. when the vehicle charges immediately and at full power as soon as it plugs in) or managed in some way. If PEVs are unmanaged, charging can coincide with the system's peak and increase ramping needs and costs through the use of inefficient and expensive “peaker” power plants. In addition to alleviating such peak loads and costs, by charging instead at times of low prices and high RE generation, managed PEVs could serve as a flexible load to help California's grid avoid RE curtailment (being turned down or off from the level that they would otherwise be producing) and save money. In this analysis we consider two forms of managed charging: time-of-use (TOU) rates that incentivize drivers to charge during off-peak times overnight, and smart charging demand response (DR) programs that allow an aggregator or other entity to directly control charging power.

Numerous studies have investigated the impacts of such managed PEV charging on power systems with RE, but most existing literature either simplifies PEV charging behavior and charging infrastructure, or the dispatch of the power system. These simplifications could lead studies to overestimate the availability of PEVS and willingness of PEV drivers to provide grid services as well as the value that PEV grid services can add to the grid. The travel demands of drivers, the location and availability of chargers, and the user acceptance of managed charging programs are important in modeling a realistic estimate of value of PEV grid services.

This analysis addresses these gaps by integrating a representation of smart and of unmanaged charging with a detailed power system model. We couple the vehicle charging outputs of the agent-based BEAM (Behavior, Energy, Autonomy Mobility) simulation model to the Energy Exemplar PLEXOS model, an industry standard tool for optimizing the economic dispatch of grid resources. We evaluate the system cost and RE curtailment impacts of the addition of 0.95 million (4% of California's current vehicle stock) to 5 million (20% of California's vehicle stock and the Governor's 2030 goal)

¹ This report is based on the methods, tools, and data from the published journal article: Szinai, Julia, Colin J.R. Sheppard, Nikit Abhyankar, Anand Gopal. “Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management.” *Energy Policy* (2019) <https://doi.org/10.1016/j.enpol.2019.111051>

PEVs under unmanaged, smart, and TOU charging strategies on the California power system in 2025, with the assumption that the state meets its renewable portfolio standard (RPS) goal of renewable energy penetration at 50% of annual electricity consumption.

BEAM and PLEXOS Model Application

The modeling methodology is illustrated in Figure 1 and proceeds as follows:

1. **BEAM Model: PEV Mobility/Charging.** BEAM simulates PEV mobility and charging behavior for three representative weekdays for about 68,000 PEVs in the San Francisco Bay Area. Charging sessions (defined by the period of time the PEV is plugged in) are simulated as unmanaged, but the time between the end of active charging and the actual unplug event concluding the session is tracked for later use and exported as an input into the next step. See Section 3.1.
2. **Charging Load and Flexibility Constraint Aggregation.** The charging session data are analyzed and aggregated by vehicle type—battery electric vehicle (BEV) and plug-in hybrid electric vehicle (PHEV)—into both an unmanaged trajectory of delivered energy, and an alternate trajectory that represents delaying charging to the maximum extent possible while still delivering the same amount of energy by the end of the session. These trajectories are treated as maximum and minimum constraints that bound possible dispatch of smart charging loads and still ensure the same end state of charge (SOC) of the PEV as with unmanaged charging. Corresponding power constraints on smart charging are also produced based on the number of connected vehicles in each hour and are aggregated by vehicle type. For TOU charging, we represent the response to off-peak TOU rates by forcing charging to begin at staggered times between 10 PM and 2 AM (to avoid inducing a sudden demand spike) for those PEVs that would already be plugged in overnight if unmanaged. We then aggregate the resulting TOU off-peak charging loads by vehicle type. In order to capture the realistic behavior of an average day, for each of the charging strategies, the data from charging sessions from the second day of a three-day BEAM run of representative weekdays are used for the load and constraint aggregation. A full week of data, constructed by calibrating to observed charging data, is then repeated to create an annual data set for each charging strategy.
3. **Load and Constraint Scaling to California Vehicle Adoption Scenarios.** The aggregated unmanaged and TOU loads and smart charging constraints produced from BEAM in Step 2, based on approximately 68,000 PEVs in the San Francisco Bay Area, are scaled from magnitudes that represent the San Francisco Bay Area PEV stock in 2016 to that of the whole state of California in 2025. The scaling occurs in two parts, from the Bay Area to each utility zone in California based on respective BEV and PHEV vehicle stock as of 2016, and then from 2016 to California in 2025 based on California Energy Commission (CEC) forecasted adoption levels. The CEC 2025 forecast includes 3 scenarios: 0.95 million, 2.1 million, and 2.5 million PEVs. We use these 3 scenarios and also add a “reach” scenario of 5 million PEVs in the state. We assume that current trends in PEV

sales will continue and that 60% of each 2025 adoption scenario will be met by BEVs and 40% by PHEVs.

4. **PLEXOS Power Sector Model.** The scaled 2025 PEV loads and constraints are loaded into PLEXOS along with power sector data from the database originally used by California Independent System Operator (CAISO) for the 2014 Long Term Procurement Planning process and updated by CAISO to reflect more recent changes on the electricity system. For each of the 4 PEV adoption levels ranging from 0.95 million to 5 million PEVs, we run PLEXOS for the four scenarios described below (no PEVs, unmanaged PEVs, TOU charging PEVs, smart charging PEVs) and export as results the total system cost, electricity prices, renewable curtailment and generation, and charging behavior (charging behavior for smart charging is dispatched by PLEXOS but unmanaged and TOU charging loads are the fixed loads from Step 3).

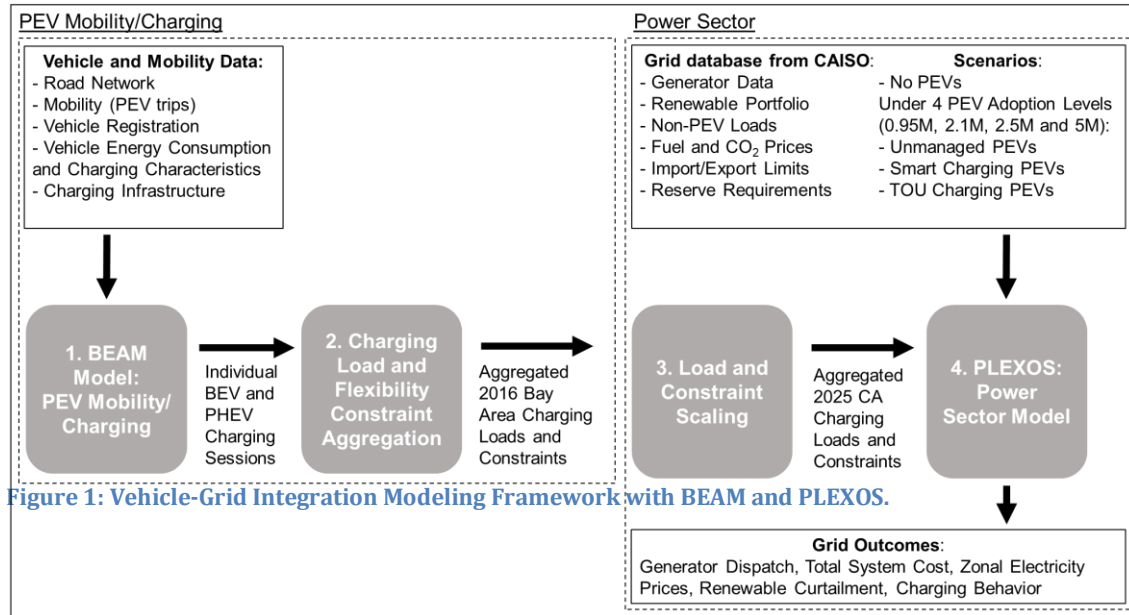


Figure 1: Vehicle-Grid Integration Modeling Framework with BEAM and PLEXOS.

Results and Analysis

We find that integrating PEVs in an unmanaged charging scenario, compared to TOU and smart charging, has the following grid impacts for California in terms of total system cost and RE:

Baseline System Costs

- When PEVs are added to the grid (as compared to a scenario with no PEVs), more fuel is used by electricity generators resulting in increased grid operating costs. The charging strategy strongly affects the degree to which costs increase. Smart charging avoids 47% (with 0.95 million PEVs) to 51% (with 5 million PEVs) of the California system costs increases that would result from unmanaged PEV charging. These costs reflect the wholesale operating costs to generate energy and do not include capital costs, transmission and distribution costs, and other

incidentals that comprise the full cost of producing and delivering electricity, or of retail electricity rates for customers.

- About 80% of these avoided cost increases can be achieved through TOU charging without the implementation cost of smart charging controls and administration; 34% (with 0.95 million PEVs) to 42% (with 5 million PEVs) of system cost increases can be averted if PEVs already plugged in at home only charge overnight, based on current TOU off-peak rate schedules.
- Smart charging provides value (by avoiding increasing system operating costs) of about \$90 to \$140/PEV per year compared to unmanaged charging. TOU provides cost savings of about \$60 to \$120/PEV per year.
- The benefits of both managed charging strategies are non-linearly related to PEV penetration, and the benefits increase as the power system approaches its generation and transmission capacity limits. If 5 million PEVs participated in smart or overnight TOU charging, capital costs of new generators or transmission could be deferred without leaving load unserved during peak hours of the year.

RE Curtailment

- Regardless of whether PEV charging is managed or unmanaged, PEVs reduce California's RE curtailment.
- Among the PEV charging strategies we consider, smart charging reduces California's RE curtailment the most relative to unmanaged charging —by an additional 12% (0.95 million PEVs) to 48% (5 million PEVs).
- In contrast, nighttime TOU charging reduces curtailment less than unmanaged charging does because of a load mismatch with times of high RE generation. With smart charging, the ability of PEVs to reduce RE curtailment is limited by the number of multi-hour, midday charging opportunities without queues at workplace or public chargers.

These grid impacts are specific to the California system and will also ultimately depend on the evolution of the generation mix, curtailment-reduction strategies (such as better coordination with neighboring balancing areas), distributed energy resources (such as other “smart” loads), and flexible supply-side resources (such as stationary battery storage). Nonetheless, most regions with aggressive PEV adoption (deployments greater than 5% of light-duty vehicle stock) can benefit from smart or TOU charging strategies to avoid operating and capital costs by reducing peak loads.

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List of Abbreviations

AAEE	Additional Achievable Energy Efficiency
BEAM	Behavior, Energy, Autonomy, and Mobility
BPA	Bonneville Power Administration
BEV	Battery electric vehicle
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CED	California Energy Demand

CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CVRP	Clean Vehicle Rebate Project
DOE	United States Department of Energy
DR	Demand Response
EIM	Energy Imbalance Market
EV	Electric vehicle
FCV	Fuel cell vehicle
GHG	Greenhouse gas
HOV	High Occupancy Vehicle
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LTPP	Long-Term Procurement Plan
MATSim	Multi-Agent Transportation Simulation
MTC	Metropolitan Transportation Commission
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
PEV	Plug-in electric vehicle
PG&E	Pacific Gas & Electric Company
PHEV	Plug-in hybrid electric vehicle
PTC	Production Tax Credit
PV	Photovoltaic
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SERA	Scenario Evaluation, Regionalization & Analysis
SMUD	Sacramento Municipal Utility District

SOC	State of charge
TEPPC	Transmission Expansion Planning Policy Committee
TIDC	Turlock Irrigation District
TOU	Time-of-use
UoS	Use of System
V1G	Vehicle to Grid (1-way)
V2B	Vehicle to Building
V2G	Vehicle to Grid (2-way)
VGI	Vehicle Grid Integration
WECC	Western Electricity Coordinating Council
ZEV	Zero emission vehicle

1. Introduction and Context

Widespread electrification of the transportation sector through the adoption of plug-in electric vehicles (PEVs)—including battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs)—can enable oil independence [2], reduce fuel costs for drivers [3], reduce local air pollution, and lower greenhouse gas (GHG) emissions [4], among other benefits. Increasing the level of renewable energy (RE) in the power system in parallel with transportation electrification can increase energy independence, reduce air pollution, and advance economy-wide GHG emission reductions [5]. In this report², we focus on California as case study because the state has been pursuing both transportation electrification and a renewable energy-dominant generation portfolio to reduce its greenhouse gas (GHG) emissions 40% below 1990 levels by 2030, and 80% below 1990 levels by 2050 [7], [8].

In 2012, the governor of California issued Executive Order B-16-2012 setting a state goal of 1.5 million zero emission vehicles (ZEVs), which include hydrogen fuel cell vehicles (FCEVs) and PEVs, by 2025 and a target of 5 million PEVs by 2030 [9]³. California has about 500,000 PEVs as of late 2019 on the road [10], which is about half of the U.S. PEV fleet and 8% of the world's PEVs [11]. With expanding model options [12]–[14], policy support [9], [15], [16], and planned charging infrastructure investments [17]–[19], California is predicted to exceed the governor's goal and have about 2 million PEVs on the road within the 2024–2030 period [20]–[22]. Alongside this growing PEV adoption, California's Renewable Portfolio Standard (RPS) requires half of electricity consumption be met by RE sources by 2030 [8] and utilities are several years ahead of schedule in meeting this target [23]. In 2018, the 50% RPS requirement was accelerated to 2026, on the way to 60% RPS by 2030 and an ultimate goal of 100% zero-carbon resources by 2045[24].

The concurrent growth of RE and PEVs have ramifications for the electricity grid. Intermittent wind and solar photovoltaic (PV) sources constitute the majority of RE [23] in California, thus the California Independent System Operator (CAISO) relies on ramping flexible generators or loads and on RE curtailment (being turned down or off from the level that they would otherwise be producing) to mitigate imbalances between supply and demand [25]–[27]. Solar PV and wind have zero marginal cost so, curtailment—although a reliable way to maintain grid stability—can increase system operating costs [25]. Subsequently, utilities deliver less RE to comply with RPS requirements, necessitating more RE capacity or flexible generation or load resources to compensate [28], [29]. PEVs could either exacerbate or help address RE-related grid challenges, depending on whether charging is unmanaged or managed in some way. If PEVs are unmanaged, charging typically occurs when drivers arrive home from their

² This report is based on the methods, tools, and data from the published journal article: Szinai, Julia, Colin J.R. Sheppard, Nikit Abhyankar, Anand Gopal. "Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management." [6]

³ We do not evaluate the impact of FCEVs in this report, because they form a much smaller share of ZEVs in California [8].

evening commutes and happens at the fastest rate permitted by the chargers as soon as the vehicles are plugged in [30], [31]. If such loads come online in the late afternoon or evening, they can coincide with the system's peak [1] and increase ramping needs and costs through the use of inefficient and expensive "peaker" power plants [30]. In addition to alleviating such peak loads and costs, by charging at times of low prices and high RE generation, managed PEVs could instead serve as a flexible load to help California's grid avoid RE curtailment and save money.

Numerous studies (for example [32]–[36], [1]) have investigated the impacts of managed PEV charging on power systems with RE, but most existing literature on PEV-grid interaction (also known as Vehicle Grid Integration (VGI)) either simplifies PEV charging behavior and charging infrastructure or the dispatch of the power system. These simplifications could lead studies to overestimate the availability and willingness of PEV drivers to provide grid services as well as the value that PEV grid services can add to the grid. The travel demands of drivers, the location and availability of chargers, and the user acceptance of managed charging programs are important in modeling a realistic estimate of value of PEV grid services [31], [37]–[39]. In addition, some studies (for example [40]) only include PHEVs, whose hybrid gasoline-electric powertrains diminish the mobility-charging tradeoff and which have a much smaller grid footprint. Robustly representing both BEV and PHEV drivers' constrained charging choices is critical for assessing the feasibility of managed charging strategies because the ability to fulfill mobility needs without compromise is paramount to drivers and charging infrastructure is constrained [31], [41]. In this study, we seek to minimize an economic objective and not necessarily an engineering objective such as load flattening [42]. This reflects the reality that the power sector is operated as a market and economic incentives are the appropriate mechanism to alter consumer behavior. In a recent study [43], the authors take such an approach, but at the scale of individual facilities, here we look at the macroscale utilization of charging flexibility.

To address the gaps in adequately modeling PEV charging, in this report we use a novel agent-based travel behavior model - Behavior, Energy, Autonomy, Mobility (BEAM) - that realistically represents the choices faced by BEV and PHEV drivers given constraints in charging infrastructure [31]. Further, we link the temporally- and spatially-explicit charging constraints and outputs of BEAM to a power systems model, PLEXOS, to simulate the interactions of PEV charging with the electric grid for integrating RE. PLEXOS is a unit commitment and dispatch model by Energy Exemplar [44], and is an electricity industry standard tool for optimizing the dispatch of grid resources. We apply this linked modeling framework to California's forecast of its 2025 power system with a 50% RPS generating portfolio. We consider the following two PEV managed charging strategies in this report⁴ as a solution to mitigate the problems with unmanaged charging [32] and high RE (both of which are in some stage of piloting in California [47]–[49]):

⁴ Vehicle-to-grid (V2G) charging is also commonly studied as a managed charging strategy. V2G allows for bi-directional power flow between the vehicle and grid such that the vehicle can both discharge excess energy to the grid and charge from the grid. We do not model bi-directional power flow from the vehicle to the grid (V2G) or participation in ancillary services [45], because of the low marginal benefits and greater complexity and cost of these strategies relative to just one-directional charging [28], [46]

- **Unmanaged Charging:** the vehicle charges immediately and at full power as soon as it plugs in.
- **Time-of-use (TOU) Charging:** Drivers are incentivized by a lower electricity rate to charge during off-peak hours, usually pre-programming the charging start time through the charger or PEV.
- **Smart Charging:** The PEV participates in a demand response (DR) program whereby an aggregator remotely and directly controls active charging to be on or off through the charger or vehicle software. The aggregator shifts charging to times that provide the most grid benefit, when prices are low or RE is abundant, bidding the aggregated flexible load of many PEVs into the wholesale electricity market.

Through this integration of BEAM and PLEXOS, we evaluate the achievable potential for PEVs to provide services to the California grid in 2025 via smart and TOU charging strategies, while maintaining drivers' same mobility and convenience and not requiring a change in travel behavior from unmanaged charging. We compare the charging strategies under four scenarios of PEV adoption based on the California Energy Commission's (CEC) forecast of 0.95 million, 1.5 million, 2.1 million, and 2.5 million PEVs for 2025 [22] and an additional "reach" scenario of 5 million PEVs. We focus on grid operating cost savings and RE curtailment reduction between unmanaged and each of the smart and TOU charging strategies, as these metrics are commonly used in the literature (for example in [25], [36], [50]–[53]) and are the relevant decision-making criteria for California system planners and utility regulators.

We find that the flexibility inherent in PEV smart charging patterns can provide substantial benefits to the power sector, primarily in lowering grid operating cost and the amount of RE that must be curtailed to avoid over-generation when supply and demand are mismatched. We also find that in California's power system with 50% RPS, overnight off-peak TOU rates can achieve the majority of the system cost savings from smart charging. Our results agree with the literature that these managed charging strategies offer cost savings and avoided curtailment relative to unmanaged charging, but these benefits are more modest than some other prior studies with less realistic power system dispatch and constraints on mobility, charging infrastructure, and driver behavior. While the cost savings and curtailment values are specific to the California system, the relative ranking of the impacts from the managed charging strategies compared to unmanaged PEVs is likely applicable to other systems considering both high PEV and renewable deployment.

2. Framework of Model Integration

To evaluate the impact of unmanaged, smart, and TOU charging on the California grid, this paper integrates two models to simulate both PEV mobility and charging behavior (using BEAM) and the operation of the electric grid (using PLEXOS). The framework of model integration is illustrated in Figure 2 and the methodology is further described below.

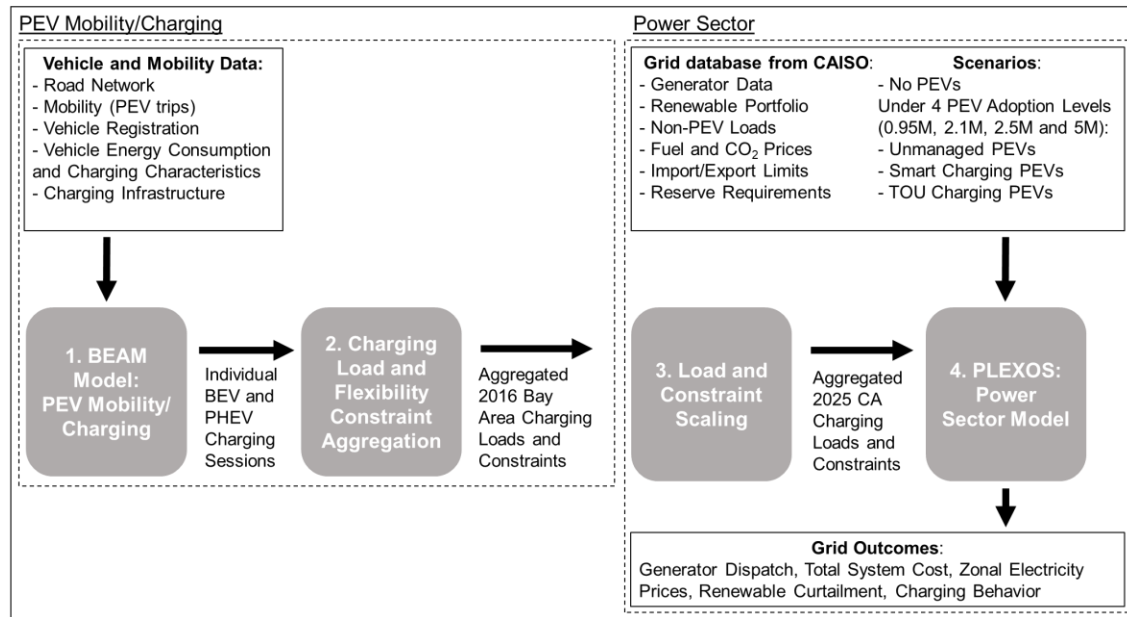


Figure 2: Vehicle-Grid Integration Modeling Framework with BEAM and PLEXOS.

1. **BEAM Model: PEV Mobility/Charging.** BEAM simulates PEV mobility and charging behavior for three representative weekdays (based on travel demand modeling from the regional transportation planning authority) for about 68,000 PEVs in the San Francisco Bay Area. Charging sessions (defined by the period of time the PEV is plugged in) are simulated as unmanaged, but the time between the end of active charging and the actual unplug event concluding the session is tracked for later use and exported as an input into the next step. See Section 3.1.
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- (e.g. that all vehicle begin the day with a full battery), for each of the charging strategies the data from charging sessions from the second day of a three-day BEAM run of representative weekdays are used for the load and constraint aggregation. A full week of data, constructed by calibrating to observed charging data, is then repeated to create an annual data set for each charging strategy.
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 4. **PLEXOS Power Sector Model.** The scaled 2025 PEV loads and constraints are loaded into PLEXOS along with power sector data from the database originally used by CAISO for the 2014 Long Term Procurement Planning process and updated by CAISO to reflect more recent changes on the electricity system. For each of the 4 PEV adoption levels ranging from 0.95 million to 5 million PEVs, we run PLEXOS for the four scenarios described below (no PEVs, unmanaged PEVs, TOU charging PEVs, smart charging PEVs) and export as results the total system cost, electricity prices, renewable curtailment and generation, and charging behavior (charging behavior for smart charging is dispatched by PLEXOS but unmanaged and TOU charging loads are the fixed loads from Step 3).

Section 3 further describes the models, analytical steps, data, and some of the key assumptions used by each of the steps above.

3. BEAM and PLEXOS Model Application and Assumptions

As outlined in Section 2, the outputs from BEAM for the San Francisco Bay Area in 2016 are processed and scaled up to each California utility area in 2025 to represent unmanaged, smart, and TOU charging PEVs in PLEXOS, which then simulates the dispatch of generation in a 2025 grid. The sections below discuss this process and critical assumptions and data used in the application of the two models.

3.1. BEAM Model: PEV Mobility and Charging

The following is an abbreviated summary of BEAM, which is described in full detail in prior work [31]. The BEAM Framework is a collection of software tools that enable

robust, spatially explicit simulation of the transportation-electric system. BEAM is an extension of the open source transportation systems modeling framework Multi-Agent Transportation Simulation (MATSim), which simulates individuals and their detailed interactions with the transportation system. BEAM simulates the daily activity patterns of individual travelers (i.e. where and when people perform activities such as at home, work, shopping mall, etc.). Agents are assumed to make trips in a PEV and they are programmed with discrete choice models to simulate their charging-related decisions. The charging decisions consider the state of charge of their battery, their remaining mobility needs for the day, the type of location (i.e. home vs work), the number of accessible chargers at a site, the level of the chargers, the cost, and the distance to their activity. The charging infrastructure is explicitly modeled including the number of parking spaces that permit physical access to the chargers, resulting in the formation of queues at occupied chargers.

3.1.1. BEAM Model Inputs: PEV Vehicle Information, Mobility, and Infrastructure

We have applied BEAM to the San Francisco Bay Area in 2016. Mobility data is based on the San Francisco Bay Area Metropolitan Transportation Commission's (MTC) activity-based travel demand model [54] [55]. The number of PEVs (~68,000) in the Bay Area and their spatial distribution are based on vehicle ownership estimates from the SERA model (Scenarios, Evaluation, Regionalization, and Analysis) developed by the National Renewable Energy Laboratory (NREL) [56]. The vehicle attributes (fuel economy, charging infrastructure compatibility) are based on a combination of resources from Original Equipment Manufacturer (OEM) model specifications and the U.S. Department of Energy (DOE) fuel economy website [57].

We assume all drivers have a charger at home and include a relatively small share of other chargers; we model about 5,400 workplace chargers (mix of Level 1, Level 2, and DC Fast chargers), 1,200 public chargers (mix of Level 1, Level 2, and DC Fast chargers), and 68,000 residential chargers (Level 2) for the San Francisco Bay Area [58]. Charging infrastructure data is from the Alternative Fuels Data Center and ChargePoint [58]. The driver preferences around charging are calibrated to observed charging session data received from ChargePoint from 2016. ChargePoint is the largest charging infrastructure provider in the United States. We assume that the driving behavior in the San Francisco Bay Area is representative of other areas of the state; according to MTC the per capita vehicle miles traveled (VMT) in the San Francisco Bay Area are virtually the same as in Los Angeles [59].

To reflect anticipated technology improvements and subsequently higher PEV utilization by our 2025 study year, we assume the BEAM PEV fleet has battery capacities—and therefore a driving range—1.5 times greater than that of the 2016 fleet. Based on analyses of the positive relationship between the range and electric vehicle miles traveled (eVMT) per typical BEV and PHEV (with greater range drivers will drive more) [58] [59], we also scale up the eVMT of our aggregated fleet to correspond with the larger batteries. With this scaling, BEVs are assumed to drive 11,000 electric-miles and PHEVs

are assumed to drive 7,600 electric-miles on average per year. Key PEV fleet and charging infrastructure assumptions used in BEAM are shown in Table 1.⁵

Table 1: Key Assumptions for PEV Models, Driving, and, Charging Infrastructure.

Vehicles						
Make/Model	Type	Battery capacity (kWh)	Fuel economy (kWh/mi)	L2 Charging limit (kW)	Direct Current Fast Charge (DCFC) Charging limit (kW)	# Vehicles
NISSAN LEAF	BEV	45	0.30	7.0	50.0	16,598
CHEVROLET VOLT	PHEV	28	0.31	7.0	50.0	10,804
TESLA MODEL S	BEV	113	0.33	20.0	120.0	10,102
TOYOTA PRIUS PLUG-IN	PHEV	12	0.29	7.0	20.0	8,599
FIAT 500e	BEV	37	0.29	7.0	50.0	3,989
FORD FUSION	PHEV	11	0.34	3.3	-	4,168
FORD C-MAX	PHEV	11	0.35	7.0	-	3,490
BMW I3	BEV	50	0.27	7.4	50.0	2,721
GEM - Various Models	BEV	19	0.20	-	-	1,806
VOLKSWAGEN E-GOLF	BEV	36	0.29	7.2	50.0	1,516
FORD FOCUS	BEV	50	0.32	6.6	-	1,265
CHEVROLET SPARK EV	BEV	30	0.28	3.3	50.0	921
TOYOTA RAV4 EV	BEV	63	0.44	10.0	50.0	764
All other BEVs	BEV	41	0.37	varied	varied	888
All other PHEVs	PHEV	17	0.47	varied	varied	858
Electric vehicle miles traveled						
Vehicle Type	eVMT	Comments				
BEVs	11,000	Average annual electric vehicle miles traveled per vehicle. Used to scale electricity demand for aggregated fleet for whole year, based on assumption that all batteries are 50% higher capacity in 2025 than they are in 2016.				
PHEVs	7,600					
Charging infrastructure						
Market Sector	Level	# Chargers				
Residential	L2	68,489				
Workplace	L1	330				

⁵ Sensitivities on the vehicle range and charging infrastructure, including levels of fast charging and workplace charging opportunities, are in the published journal article: [6].

Workplace	L2	4,900
Workplace	DCFC	210
Public	L1	130
Public	L2	900
Public	DCFC	160

3.1.2. BEAM Model Outputs: Charging Session Information

Using all the mobility and infrastructure data described above, the BEAM simulation runs and outputs data from each PEV's charging sessions, defined by the amount of time the PEV is plugged in to the charger (but not necessarily actively charging the whole time), include the following details:

- Time
- Location
- Driver ID
- Charger ID
- Charger type (Level 1, Level 2, DCFC)
- Activity type
- Energy delivered (kWh)
- Maximum power of the charger & vehicle's charge controller (kW)
- End of activity power delivery
- End of the plug session (entire time the vehicle is left plugged in)

3.2. Unmanaged, TOU, and Smart Charging Loads and Constraints in BEAM

The charging session outputs described in Section 3.1.2 are recorded for individual BEVs and PHEVs and are used as described below to estimate loads and constraints for unmanaged, TOU, and smart charging strategies.

3.2.1. Unmanaged Charging Load

Charging sessions are first simulated in BEAM as unmanaged, such that a PEV starts charging as soon as it is plugged in, and we record the cumulative energy delivered during each PEV's session as the unmanaged load.

3.2.2. TOU Charging Load

For the TOU charging case, we represent the response to off-peak TOU rates by forcing charging sessions in BEAM to begin at staggered times (to avoid inducing a sudden demand spike) between 10 PM and 2 AM—approximately the range of start times of California's current residential off-peak rate periods [62]–[64]—for those PEVs that would already be plugged in at home overnight if unmanaged. We do not explicitly model a particular TOU electric rate but assume that the price would be sufficiently low to incentivize all drivers to program a timer for charging at off-peak times. We record the energy delivered during each PEV's TOU charging session.

3.2.3. Smart Charging Load and Constraints

To create a realistic, bounded estimate of the impact of smart charging, for this analysis, the flexibility to shift load is limited to shifting within a single charging session, rather than allowing a shift in the time of day of the charging session entirely. A charging session is defined by the time the vehicle is plugged in at a station even if it is not actively charging during this entire plug-time. We limit the shifting to the times that vehicles are plugged in under the unmanaged charging BEAM simulation. Therefore, during the unmanaged charging BEAM simulation, the time between the end of active charging and the actual unplug event concluding the session is tracked and exported.

Implicit in this methodology is that BEAM assumes perfect foresight into the length of the charging session; similar to previous studies [65], a driver would be expected to input their expected parking time and end SOC into the charger and/or vehicle's software. We limit smart charging flexibility to the time windows of unmanaged charging session because 1) we assume that even with incentives, people will not readily shift their charging session to an entirely different time of the day, given that charging infrastructure is not ubiquitously available, 2) drivers do not usually unplug immediately after active charging completes, and 3) there is still flexibility available within the charging session without disrupting mobility or other user preferences.

When the PEV participates in smart charging, the vehicle charges at a different time and/or rate (power) than it would otherwise if unmanaged. However, in constructing the bounding maximum and minimum energy constraints, we treat the end SOC from unmanaged charging in BEAM as a required target for the smart session. This treatment ensures that any management of charging would have no impact on mobility in BEAM.

For three representative PEVs, Figure 3 shows an illustrative example of the maximum (earliest) and minimum (latest) smart charging cumulative energy constraints for the first week of the BEAM simulation. The maximum energy boundary corresponds to the same

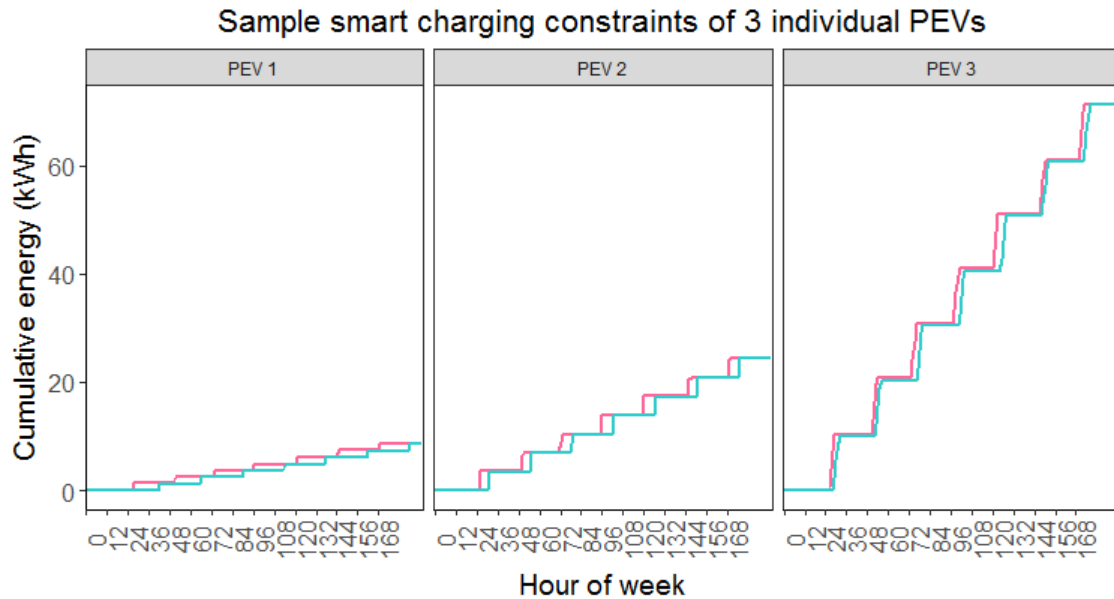


Figure 3: Example Maximum and Minimum Cumulative Energy Constraints for Smart Charging.

energy as unmanaged charging, when active charging begins immediately. The minimum energy boundary corresponds to delaying active charging until the last possible moment while still reaching the same target SOC. The two curves remain flat in between charging sessions when no charging load occurs. Within the boundaries of these two curves, any monotonically increasing trajectory can be achieved with smart charging while still reaching the target SOC, subject to the maximum charging power of the vehicle and charging equipment. We record the energy values of these maximum and minimum constraints and the power limits of the vehicle and/or charger.

Unlike the unmanaged and TOU charging strategies whose loads are determined entirely by the BEAM simulation and passed through as fixed loads to PLEXOS, the final smart charging loads are the result of the PLEXOS optimal dispatch within these constraints from BEAM. As described in more detail in Section 3.5.2, as part of the optimization in PLEXOS we also enforce a constraint to conserve total energy shifted by the end of each month for the aggregation of vehicles to account for any edge effects that could occur by any charging sessions occurring overnight at the end of a month.

3.3. Aggregation of Charging Loads and Constraints to SF Bay Area

Following the methodology of Xu et al. [65], for each charging strategy, we aggregate the energy outputs (and energy and corresponding power constraints for smart charging) by summation across the individual vehicles modeled for the San Francisco Bay Area in BEAM. For example, for smart charging, the aggregated maximum cumulative energy delivered to a fleet by hour 10 is equal to the sum of the maximum energy delivered to each vehicle in that fleet by hour 10. For each charging strategy we do this type of summation separately for BEVs and PHEVs for the entire San Francisco Bay Area.

The aggregated Bay Area constraints from a typical weekday (the second day of a three-day BEAM run of representative weekdays) are used to construct a full week of constraints based on the weekly load shapes from the observed ChargePoint data set described in Section 3.1. This construction occurs by repeating the hourly load profiles from BEAM seven times to create a week and then scaling the profiles separately by charger type (residential, workplace, and public) and weekday/weekend to match the normalized daily average load profiles from ChargePoint by charger type and day of week. Finally, these weekly power and energy constraints are repeated to complete a data set spanning an entire year for use in PLEXOS.

3.4. Scaling of Charging Loads and Constraints to CA Vehicle Penetration Scenarios

The aggregated charging session loads and constraints from Section 3.3 are simulated in BEAM for approximately 68,000 vehicles (PHEV and BEV combined) in the San Francisco Bay Area in 2016. We scale these outputs to represent the eight separate California utility zones modeled in PLEXOS in the forecast year of 2025. The factors used to scale to the eight utility zones are based on the ratio of the number of BEVs and PHEVs in the Bay Area counties included in BEAM relative to the number of BEVs and PHEVs in the eight utility areas modeled in PLEXOS, using California's CVRP data, which covers the whole state and includes data on county and utility area of each rebate recipient [15]. The factors used to scale from a 2016 estimate of PEV penetration to 2025

are derived from the ratio of the California total cumulative number of BEVs and PHEVs in 2016 relative to the projected 2025 vehicle penetration levels from the CEC’s 2015 California Energy Demand (CED) forecast and the added “Reach” bookend scenario as shown in Table 2 [66]. The PEV penetration forecasts represent 4% (0.95 million), 8% (2.1 million), 10% (2.5 million) and 20% (5 million) of today’s light-duty vehicle stock (approximately 25.2 million) in California.

The CEC’s aggregate 2025 vehicle population forecast is for PEVs and does not show the split of the population between PHEVs and BEVs. Therefore, we assume that current trends in PEV sales will continue and that 60% of the 2025 stock level will be met by BEVs and 40% by PHEVs, which is the split of PEV rebates currently seen in the CVRP database [15]. Table 2 shows the resulting scaled 2025 annual load values summed across all utility zones in California for the unmanaged charging case in each of the PEV penetration scenarios. The total loads for the smart and TOU cases are within 1% of the total unmanaged load due to rounding and the load shifting efficiencies assumed for smart charging.

Table 2: Scenarios of 2025 California PEV penetration and Energy.

Scenarios of 2025 California PEV penetration and energy				
	Low	Mid	High	“Reach”
Total California Annual PEV Unmanaged Charging Load (GWh)	3,016	6,668	7,938	15,876
Total Stock of PEVs	950,000	2,100,000	2,500,000	5,000,000
Stock of BEVs (60%)	570,000	1,260,000	1,500,000	3,000,000
Stock of PHEVs (40%)	380,000	840,000	1,000,000	2,000,000
PEVs % of Current CA Auto Stock	4%	8%	10%	20%

3.5. PLEXOS Power Sector Model

The purpose of this analysis is to assess the broader electric system and RE integration impact of PEV managed charging, and in general of the forecasted penetration of PEVs at the bulk power system level in California. In order to do so, we use PLEXOS, an industry standard unit commitment and economic dispatch (also referred to as production cost) software developed by Energy Exemplar, Inc. [44]. There are several examples in the literature of the use of PLEXOS as a way to model the grid impacts of PEV penetration and different charging regimes [67]–[69].

PLEXOS performs a unit commitment and economic dispatch simulation (deterministically and not stochastically) using mixed-integer programming to minimize the total system cost, subject to several operational constraints including generator unit commitment, generator ramping, start and shutdown times, minimum stable generation levels, carbon price/emission caps, hydropower energy limits, import/export restrictions, transmission line bounds, etc. In this analysis, we use a version of the PLEXOS database originally created by CAISO for the state’s 2014 Long Term Procurement Plan (LTPP) regulatory process and then revised by CAISO to include certain modeling assumptions and data for a 50% RPS. We use this database in order to simulate the operating practices

and energy markets of the CAISO and the rest of the Western Electricity Coordinating Council (WECC) in the year 2025. More details on the database are in Section 3.5.3. We use the PLEXOS 7.4 R01 x64 edition, and the Xpress-MP solver 28.01.13 for the optimization.⁶

We run the model one month at a time consecutively for the 12 months of 2025. Each run first optimizes over a time horizon of one month to accommodate the generators with monthly energy limits, such as large hydro plants, and then conducts daily chronological optimizations to balance load by dispatching generation for each hour. Through this process, PLEXOS co-optimizes for energy and ancillary services to meet load and ancillary services requirements and achieve a minimum cost result [52]. Together the result is an hourly solution that includes power plant dispatch, cost, zonal electricity prices, transmission line flows, imports, and exports. The solution represents the day-ahead CAISO market and does not separately model the real-time CAISO market.

In the following sections, we provide an overview of our methodology of representing aggregate PEV fleets in PLEXOS, the application to the CA power sector, and the scenarios we use for our analysis.

3.5.1. Unmanaged and TOU Charging in PLEXOS

For the unmanaged and TOU charging scenarios, for each utility zone we add the aggregated and scaled 2025 PEV load from Section 3.4 to the non-PEV load (which are already developed by state agencies for other grid planning studies) as a fixed load profile in PLEXOS.

3.5.2. Smart Charging in PLEXOS

The smart charging aggregated PEV fleet from Section 3.4 is added to PLEXOS as a combination of “inflexible”⁷ load plus a dispatchable storage resource. We add the “inflexible” PEV load profile to the non-PEV load for each utility planning area or zone in the same way as described above for unmanaged charging. Then we configure a dispatchable storage resource similar to [67] which can both generate and consume energy in response to fluctuations in electricity market conditions. At the start of each monthly simulation, the storage resource is full. If the storage resource is not dispatched by the PLEXOS optimization, the smart PEV load equals the load defined for the unmanaged scenario. But when the storage resource generates (discharges energy), this has the net effect of reducing the load demanded by the smart PEVs and therefore the cumulative energy delivered to the PEVs falls below the maximum energy constraint. When the storage resource consumes (charges), the PEVs use more net energy than the

⁶ We set the model performance MIP relative gap to 0.1 percent, with a max time of 4,000 seconds. The MIP gap is a measure of the quality of the integer solution by indicating the difference between the best known integer solution and the best known bounding linear solution (through the branch-and-bound algorithm).

⁷ “Inflexible” is in quotes to remind the reader that we are using a combination of inflexible load and storage in PLEXOS to model a flexible load. The word “inflexible” in this context should not be interpreted as fixed load that can’t be shifted.

unmanaged scenario and the cumulative energy begins to return toward its maximum constraint.

We constrain the total size (in GWh) of the smart charging storage facility to be the largest difference between the maximum and minimum energy constraints of the aggregated PEVs in each utility zone. We limit the storage resource's hourly SOC to be greater than the hourly difference between the maximum and minimum cumulative energy constraints of the aggregated vehicles. We also enforce time-varying maximum power constraints on discharging the storage resource, corresponding to the unmanaged load. The maximum power for charging the storage resource is constrained by the vehicle and charger capacity of all grid-connected PEVs in each time period. We set the round-trip efficiency of the storage resource to 99% instead of 100%, such that PLEXOS first dispatches a zero-marginal-cost generator before the flexible smart charging load. Lastly, because we run our PLEXOS simulation one month at a time, we account for any edge effects by constraining the aggregation of vehicles to return to the original SOC by the end of each month. With this monthly constraint to rebalance, and the storage efficiency of 99%, the total energy of smart charging over the course of the month is <1% higher than the energy from the unmanaged scenario.

3.5.3. Grid Assumptions and Input Database

We have populated PLEXOS dispatch model with the grid data and assumptions as described below.

3.5.3.1. Overall geographic area and spatial resolution

We use a variant (most recent publicly available at the time of the analysis) of the 2014 Long Term Procurement Plan (LTPP) PLEXOS database from the CAISO, which was also vetted by a number of stakeholders and staff of the California Public Utilities Commission (CPUC) and CEC [52]. A number of other studies have been conducted based on versions of the same original 2014 LTPP database or earlier versions [25], [51], [70], [71]. For this analysis, we use a version (released in November 2016) that the CAISO updated to conduct a special study of the grid impact of a 50% RPS and analyze the impact of additional bulk energy storage for the 2015-2016 Transmission Planning Process [29], [53].

The geographic scale covers the entire WECC area and we run the model at the hourly temporal level for one year.⁸ There are 25 zones in the model, including eight in CA based on utility planning areas: Imperial Irrigation District (IID), Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric (PG&E) Bay Area, PG&E Valley, Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Sacramento Municipal Utility District (SMUD), and Turlock Irrigation District (TIDC) [52]. Key assumptions on the grid inputs are listed in the following section. Additional

⁸ The original 2014 LTPP PLEXOS database was constructed by CAISO for 2024. CAISO updated this version with loads for 2025, but did not change the model horizon or file labels from 2024 to 2025 in PLEXOS. In order to maintain consistency with CAISO's database, for this study we maintained the PLEXOS model horizon for 2024, but refer to the results as for the year 2025 because the load is from the 2025 CEC forecast.

assumptions CAISO originally used in assembling this data are described in the CAISO testimony for the 2014 LTPP CPUC proceeding [52], and in the CPUC ruling on the 2014 LTPP planning assumptions and scenarios [72]. Modifications CAISO made to the original 2014 LTPP database are also described in [29], [53].

There are number of limitations of the particular PLEXOS database we used in this study. Because the model was built primarily for planning purposes, the model is run as a combined unit commitment and economic dispatch for the day-ahead without a separate real-time market to reflect CAISO operations. This simplification does not capture the uncertainty of the energy market due to changes between a day-ahead dispatch and real-time (such as in the load or in renewable generation) and assumes perfect foresight of the day-ahead market [51]. Additionally, the model is run deterministically and only uses one set of renewable profiles and therefore does not capture any uncertainty in the energy mix to meet the 50% RPS. This database is also a zonal PLEXOS model, therefore, the transmission network is broadly represented as paths between utility zones and does not cover individual lines. Although the zonal representation improves the computational time of the model, because of this simplification, we cannot examine the impacts the addition of PEV is expected to have on transmission congestion. Lastly as elaborated in a previous study that used PLEXOS [51], because of the aggregation of the transmission network, and the use of marginal costs as a proxy for generator bids for energy and reserves (not reflecting any individual generator's particular bidding strategy), the electricity prices produced by the model generally under-estimate hourly prices.

3.5.3.2. Load and Distributed PV Generation

The California loads and distributed rooftop solar PV estimates for the analysis came from the 2014 California Energy Demand (CED) Forecast (2015 – 2025) developed by the CEC [53], [73]. The original load for the California balancing areas modeled in the PLEXOS database, net of distributed solar PV and energy efficiency (EE), is 297,686 GWh. We then remove the 6,108 GWh of PEV load included in the original load forecast to avoid double-counting when adding the PEV loads from BEAM [66]. Non-CA loads come from the WECC Transmission Expansion Planning Policy Committee (TEPPC) 2024 Common Case.

3.5.3.3. Renewable Generation

For all PLEXOS runs we use the RE profiles that CAISO created to test the final 50% RPS state target [8]. While the 50% RPS target is for 2030, because utilities are ahead of schedule in achieving this goal, we model 50% RPS by 2025 [23]. The mix of renewable generation in the database builds on generation profile data from NREL [53]. Data for already built renewable projects came from the CEC and the CAISO simulated the buildout of additional generation to reach the 50% target using the RPS Calculator [74], a public tool used to test different renewable portfolios to meet the RPS mandate [53]. The total energy and capacity quantities are listed in Table 3. These energy quantities exactly meet the forecasted 50% of statewide retail sales (not the load as modeled in PLEXOS), and if any of the renewable energy is curtailed, the state will be out of compliance with the RPS goal [52].

Table 3: Renewable Capacity and Annual Energy Production in 50% RPS Scenario from CAISO (includes RPS-eligible out-of-state capacity)

	Biogas	Biomass	Geothermal	Small Hydro	Large Solar PV	Small Solar PV	Solar Thermal	Wind	Total
Capacity (MW)	228	635	2,076	986	19,316	2,073	1,021	14,649	40,986
Energy (GWh)	1,511	4,120	15,775	3,104	53,611	4,995	2,412	39,779	125,307
% of RPS Energy	1.2%	3.3%	12.6%	2.5%	42.8%	4.0%	1.9%	31.7%	100.0%

3.5.3.4. Renewable Curtailment

We allow for California solar PV, wind, and solar thermal generation to be curtailed. Curtailment can be invoked because of local or system congestion, but typically occurs when there is over-generation. Over-generation is usually caused when supply from must-run resources such as nuclear, combined heat and power (CHP), and minimal levels of thermal generation exceeds load plus exports [75]. In PLEXOS, RE generates until the electricity price reaches a negative floor price and is curtailed [52]. We use a floor price of -\$150/MWh, which is the current floor for economic bids in the CAISO market [75].

3.5.3.5. Reserve Requirements and Frequency Response Standard

CAISO developed load, wind, and resource profiles based on CEC load and resource assumptions [52], as well as NREL data [53]. Using these profiles, the CAISO conducted a statistical analysis to calculate the regulation and load-following reserve requirements for the hourly PLEXOS database. These reserve requirements are based on variability and forecast error in load, wind, and solar resources [76]. Regulation reserves in each hour are meant to cover the maximum difference between the actual minute-by-minute CAISO generation requirement and the 5-minute-ahead forecast [52], [76]. Load-following reserves in each hour must be sufficient to cover the maximum difference between the hourly schedule and the 5-minute-ahead net load forecast [52], [76]. In addition, spinning and non-spinning reserves (3% of load) were included in the CAISO inputs [52]. We use the reserve requirements that CAISO calculated for this analysis corresponding to the 50% RPS profiles because we do not make any additional changes to the wind and solar profiles, and the changes in the PEV load shapes (between the original PEV load that we remove and the inflexible PEV load we add) are not significant enough to change the forecast error of the load.

In our analysis, per CAISO's updated 2014 LTPP database, we allow for renewable generators to provide up to 50% of their energy as downward load-following reserves, satisfying up to 50% of the load-following down requirement [53]. A recent study assessing a 50% RPS in CA found that allowing renewable generators to provide downward reserves can greatly reduce the amount of renewable curtailment and lower emissions from fossil generators that would otherwise be used [25]. The assumptions and

scenarios recommended for the 2016 LTPP also include a scenario to test the impact of allowing renewable generators to provide operating reserves [77].

Per the recommendations of the 2016 LTPP assumptions, our analysis also removes a requirement for 25% local generation and instead replaces that with a frequency response requirement. To comply with the new NERC BAL-003-1 standard, the frequency response requirement is that at all times CAISO must 752 MW of headroom (available capacity). Half of the headroom requirement is met by storage and/or combined cycle generators, while the other half is to be met by hydro resources [77]. The elimination of the 25% local generation requirement is also a sensitivity tested to increase flexibility of the system by several other studies [25], [50].

3.5.3.6. Stationary Storage

We include 1,325 MW of stationary storage (transmission connected, distribution system connected, and behind-the-meter connected) ordered by the CPUC storage mandate by 2020 [78],[52]. The storage resources are modeled in the CAISO data with a round-trip efficiency of 83.3%, and 873 MW of the transmission and distribution connected storage is modeled with the ability to provide ancillary services [52].

3.5.3.7. Demand Response

The non-PEV related DR modeled in the CAISO database only reflects event-based DR to lower the peak energy usage during contingencies, when high trigger prices are reached (some DR resources have limits on the number of hours each month they can be called) [52]. Non-event based DR is already embedded as a modifier to the load forecast described in Section 3.5.3.2. We only include these DR resources to be consistent with CAISO's data, but by 2025 there may be a much higher DR penetration, and possibly additional DR products, to reflect the large DR resource potential and need for load flexibility that has been identified in the recent CPUC Demand Response Potential Study [28].

3.5.3.8. Conventional Generators

We include the conventional thermal and hydro generators as specified in the CAISO updated 2014 LTPP database. Hydro generators are either run-of-river (and modeled with a fixed generation profile) or dispatchable (and constrained by maximum and minimum energy levels). The data that the CAISO used to characterize thermal generators originated from the CPUC Scenario Tool, CAISO Master Generating Capacity list, and the WECC's TEPPC 2024 Common Case [52], [53]. This information includes start-up, shut-down, variable operations and maintenance (O&M), fixed O&M, heat rate, emissions rate, energy limits (for hydro), and any other related cost information. CAISO has also included several generic conventional generators in its database to represent CPUC authorized procurements of new generation in CA that is expected to be built by 2024 [72]. A list of conventional generators that have been approved and are included in the PLEXOS database is in the 2016 LTPP scenarios documentation [77].

3.5.3.9. Fuel and Carbon Dioxide Emissions Prices

Fuel prices vary based on the location of the generators. Natural gas price forecasts for California come from the CEC, and the natural gas and coal prices for the rest of WECC come from the TEPPC Common Case [52], [53]. Based on CAISO's own forecast of GHG price we assume emissions cost \$20.75/metric ton CO₂-eq, a value within the historical range of prices under the CA AB32 cap and trade program [79]. Per the CAISO's methodology, for fossil resources imported from outside of CA, except dedicated imports, a CO₂ cost adder (determined by the California emissions price times average emissions rate of 0.435 metric ton/MWh) is added to the transmission wheeling charge [52]. The transmission adder is 20% of this value for Bonneville Power Administration (BPA), which primarily produces hydropower [52].

3.5.3.10. Imports and Exports

We constrain California's out-of-state net-exports such that exports minus imports cannot be more than 2000 MW in any given hour [77]. This allows for some excess RE to be exported rather than curtailed [25], [50]. We also model some dedicated imports to California entities, including from certain fossil and large hydropower resources, and 70% of out-of-state RPS renewable resources [52].

3.5.3.11. Retirement of Diablo Canyon Nuclear Plant

In 2016, PG&E announced that it will not seek relicensing of its Diablo Canyon nuclear power plant (about 2,200 MW of capacity). The current license expires in 2024 for one unit and 2025 for the other [80]. For the purposes of extrapolation of our results to future years, we turn off both Diablo units in PLEXOS for all of 2025.

3.6. Vehicle-Grid Integration Scenarios: PEV adoption levels and charging strategies

We assume California reaches its 50% RPS target (approximately 125 TWh of RE) and we run the hourly PLEXOS model for the whole western U.S. grid for the four PEV charging cases below for 2025, the target year for some of California's vehicle electrification goals [3]:

- No PEVs
- All PEVs charging unmanaged
- All PEVs participating in smart charging
- All PEVs responding to an overnight off-peak TOU rate.

For each case, we test four levels of PEV adoption (Table 2). The PLEXOS optimization dispatches the generators to minimize cost while meeting the load, yielding as output the California total system cost, RE curtailment, generation, zonal electricity prices, and smart charging profile (the unmanaged and TOU charging profiles do not change with grid dispatch).

4. Results and Analysis

After running PLEXOS with the three cases described in Section 3.6, we analyze several grid-related outcomes of vehicle-grid integration (VGI): PEV smart charging dispatch, total system operating costs, and renewable generation and curtailment. We produce results for all of WECC, but the discussion of results in the following sections focus on California.

4.1. Smart Charging Dispatch Compared to TOU and Unmanaged Charging

Before analyzing the statewide grid impacts, we first compare the different PEV charging profiles and how they relate to several key system metrics. As mentioned, the unmanaged and TOU charging loads are directly passed-through as the aggregated and scaled loads from BEAM, and do not change with PLEXOS dispatch. Smart charging loads, however, are the result of the PLEXOS dispatch optimization, within the aggregated constraints from BEAM. Figure 4 shows the charging loads for the various strategies and the corresponding system metrics with a 2.5 million PEV adoption level, averaged across three seasonally representative months of winter, spring, and summer grid operation.

On average, BEAM simulates PEVs primarily leaving home around 7am, with a steady stream of remaining PEVs departing home between 7am and 4pm [81]. Row B shows that the majority of the unmanaged PEV load subsequently occurs between 3pm and 11pm, after the predominant commute home and coinciding with the typical evening peak of the system's load net of PV, solar thermal, and wind generation (Row A). TOU charging, by design, is concentrated overnight at home starting at 10pm and lasting until the early morning (Row B), avoiding peak load times (Row A) but also most times of RE curtailment (Row C). Row B shows that smart PEVs, dispatched by PLEXOS and subject to all the constraints as modeled in BEAM, charge in the late morning (delayed residential charging) and the late afternoon (delayed workplace charging or residential charging as drivers arrive home) to reduce RE curtailment, surging again as soon as prices drop around 11pm. This pattern follows the timing of low-priced generation shown in Row D: solar during the middle of the day and wind plus baseload plants overnight. However, even when there are high levels of RE curtailment and negative pricing in the middle of the day, which would be ideal times for PEV loads, most load flexibility is in the middle of the night when drivers are parked for longer periods at their homes (and where everyone has a charger under our assumptions).

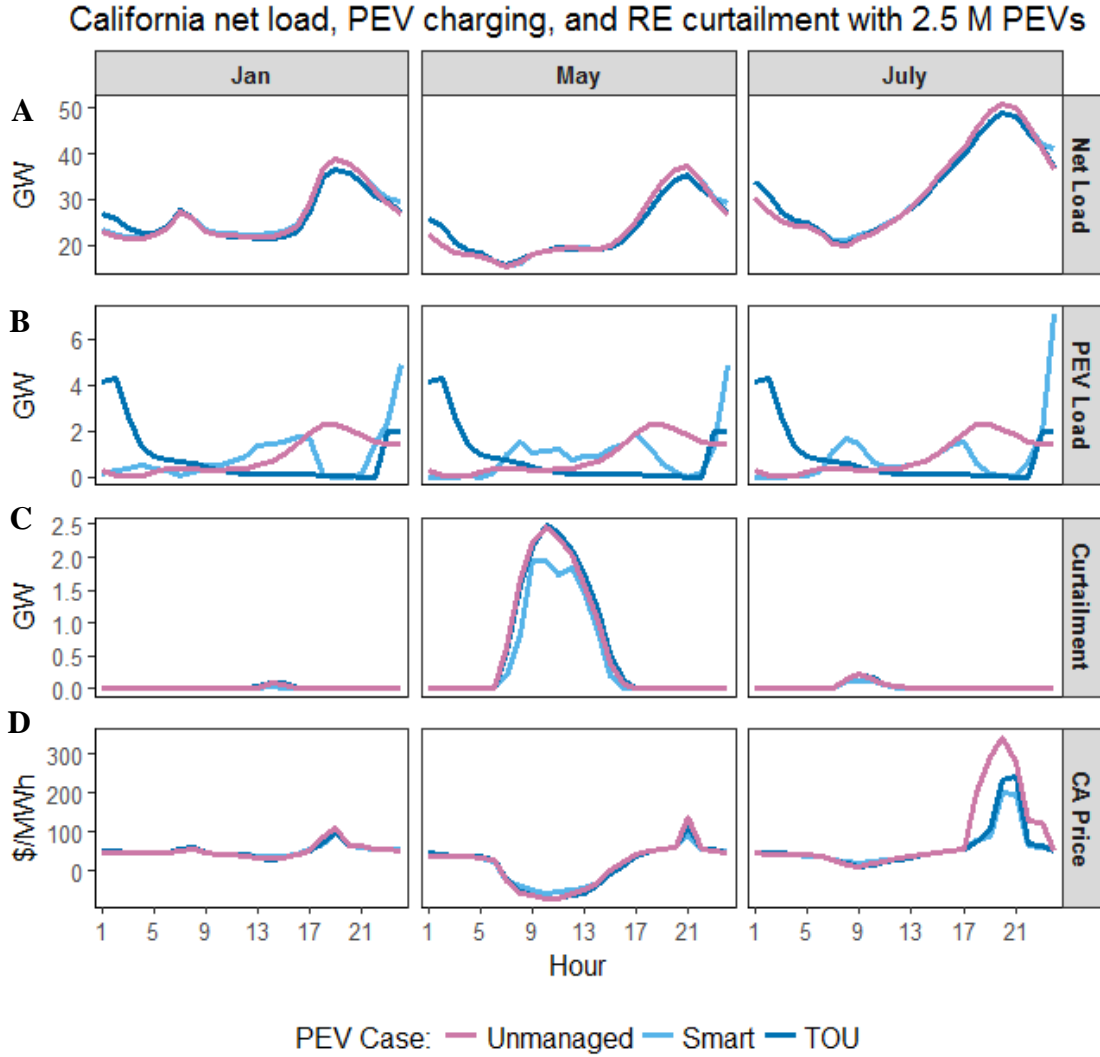


Figure 4: California net load, PEV charging, and RE curtailment with 2.5 M PEVs.

4.2. Total System Cost

4.2.1. Total System Cost Calculation

One of the key PLEXOS results is an estimate of the total system cost, often referred to as production cost. Total system cost is a commonly used metric (for example in [25], [50]–[53]) calculated with dispatch models to estimate a system’s total operating cost to meet its load. In general, the system cost is calculated from a societal perspective of the wholesale electricity market and is comprised of generation costs (including fuel, startup and shut down, and variable O&M) and emissions cost. Because annually California is a net importer of electricity from neighboring regions [52], we also include the costs of imports and the revenue from exports (negative costs) in our calculation of total system costs. However, because our analysis holds the generation and other infrastructure of the system as fixed as we add PEV loads, our estimate of the total system cost does not include capital costs (for building new power plants, transmission or distribution or other

infrastructure to enable flexible load). We also do not include capacity payment costs, or other annual maintenance costs for the system, which would comprise a more complete assessment of the costs of producing and delivering electricity to the end-user. A calculation of retail rate impacts of PEVs to the customer is also outside of the scope of this analysis.

In order to estimate the California-wide system cost, we first sum the total system cost for all the utility zones within the state. We then add costs of both “unspecified net imports” (net imports of power from unspecified generators that would be purchased on the spot market to balance load) and “dedicated imports” (power from specific generators that is dedicated to be sent to Californian utilities per long-term contracts). For unspecified imports we add the product of net interstate power flows and the electricity price in the region receiving the power per the method of [50]. For dedicated imports, we add the generation cost of the amount of power sent to California from the specific, contracted generators.

4.2.2. Total System Cost Result

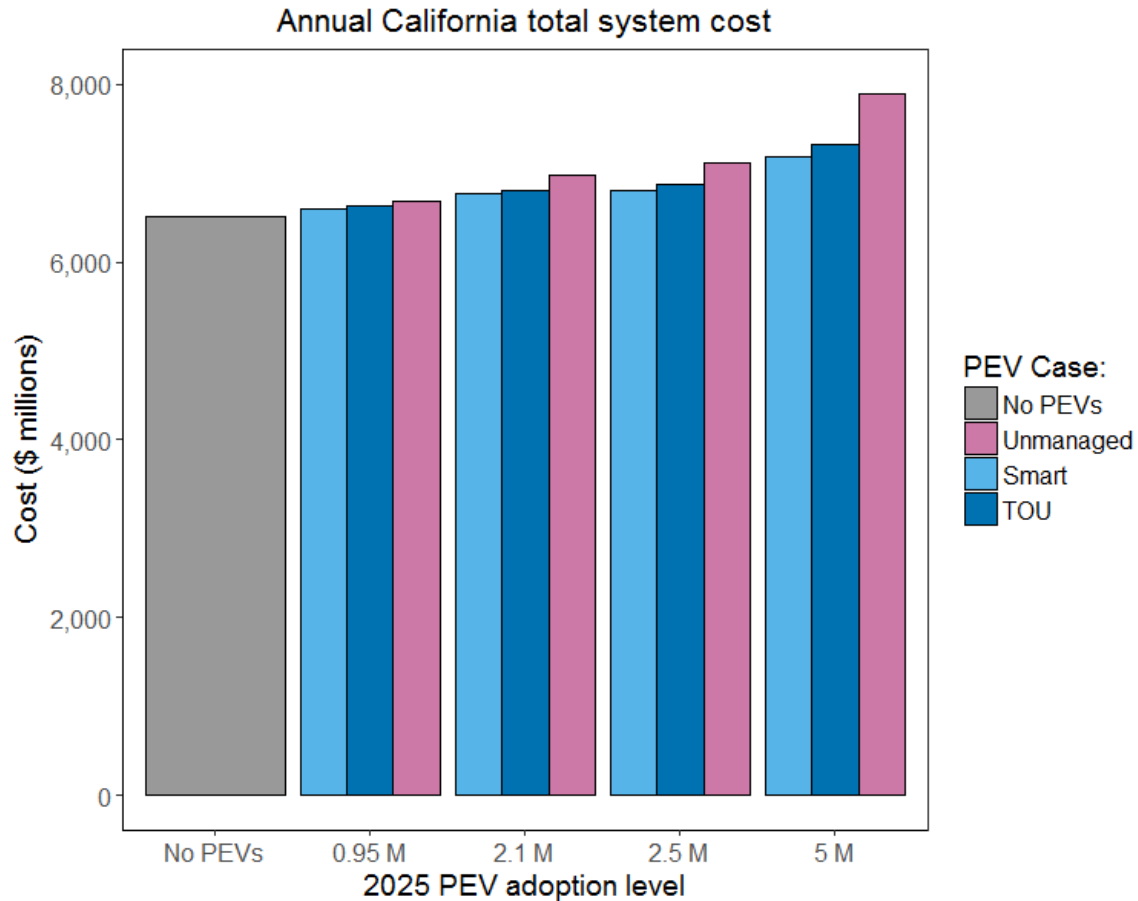


Figure 5: California 2025 Annual Total System Cost.

Relative to the base case with no PEVs, the total system cost rises with all scenarios of PEV adoption levels and charging strategies because of the increased generation needed to meet the added load. However, as noted by Richardson [32], the PEV charging

strategy employed affects the total cost increase to the system from the added load. For the same number of vehicles, smart charging avoids 47% or about \$80 million (with 0.95 million PEVs) to 51% or about \$700 million (with 5 million PEVs) of these incremental costs per year compared with unmanaged charging, as show in Figure 5 and in Table 4. Compared to what the total system cost increase would be with unmanaged PEV charging, TOU charging avoids 34% or \$60 million (with 0.95 million PEVs) to 42% or about \$580 million (with 5 million PEVs) of incremental costs (Figure 5, Table 4).

Table 4: California Total System Cost (Absolute) and System Cost Value of Smart and TOU relative to Unmanaged Charging

PEV Scenario	PEV Adoption (Millions)	Charging Strategy				Value of Smart Relative to Unmanaged Charging		Value of TOU Relative to Unmanaged Charging	
		Base (No PEVs)	Unman	Smart	TOU	Avoided Incremental Cost (\$Million)	% Avoided Cost	Avoided Incremental Cost (\$Million)	% of Avoided Cost
No PEVs	0	\$6,508	NA	NA	NA	NA	NA	NA	NA
Low	0.95	0	\$6,687	\$6,603	\$6,626	\$83	47%	\$60	34%
Mid	2.1	0	\$6,986	\$6,764	\$6,806	\$222	46%	\$179	38%
High	2.5	0	\$7,110	\$6,806	\$6,865	\$304	50%	\$245	41%
Reach	5	0	\$7,893	\$7,185	\$7,317	\$707	51%	\$576	42%

Smart charging incurs lower system costs in California relative to unmanaged charging, in part because peak load is reduced and more PEV load is served by RE (Figure 4) and because net imports decrease from out-of-state. TOU charging decreases system costs relative to unmanaged charging because of reduced load (Figure 4)—and thus reduced ramping primarily from natural gas generation—during evening peak demand hours. Under both managed charging strategies, the system dispatches less traditional and expensive DR to reduce peak loads and also displaces some use of stationary storage, increasing the option value, or the opportunity for future use, of these flexible resources for other grid needs.

4.2.3. System Cost Benefits per Vehicle

While not all of the avoided system costs benefits achieved by smart or TOU charging would necessarily be returned to the PEV driver (depending on the business model and incentives of the PEV smart charging aggregator and the utility rate structure), if we divide the cost savings by the number of PEVs modeled, this represents an average savings of \$88/PEV per year with 0.95 million PEVs and \$141/PEV per year with 5 million PEVs on the system (Figure 5). PEVs that charge during off-peak TOU periods achieve 72% to 81% of these cost savings resulting from smart charging. On average, that translates to annual system cost savings from TOU of \$63/PEV per year with 0.95 million PEVs and \$115/PEV per year with 5 million PEVs (Figure 6). A review of the VGI and V2G literature shows that PEVs participating in different electricity markets show a typical profit in the range of \$100 – 300 per vehicle. The values we see in this study are below or in the lower end of this range, likely because unlike the majority of prior studies, we include more realistic constraints on driver mobility behavior and charging infrastructure, as well as a full power systems dispatch model.

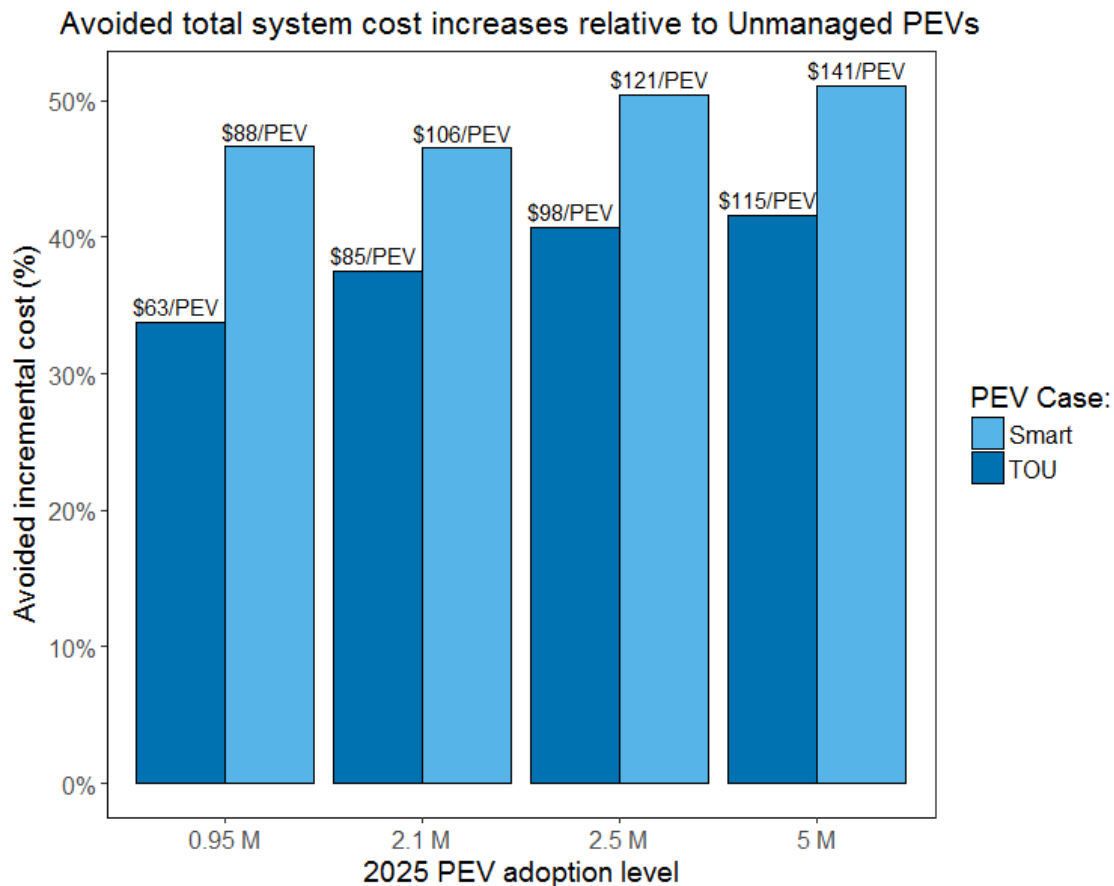


Figure 6: Avoided Cost Benefits from Smart and TOU Charging Relative to Unmanaged PEVs

4.2.1. System Cost Spikes and Deferred Generating Capacity Expansion

The system cost results also show that, compared with unmanaged charging, smart or TOU charging can also defer the addition of new generating capacity. Once 5 million

PEVs are added, in the case of unmanaged charging, the PEV load stresses the system peak to the point that about 2,600 MWh of load are unserved in California over the course of 2 days in July, while the load of 5 million PEVs participating in smart or TOU charging can still be accommodated by existing generators without any unserved load. In our simulation, in such a case when there is not enough generation to meet load (either within a utility region or through more imports), a region's electricity price spikes up to the level of a market ceiling price set at \$2000/MWh. Because we calculate the total system cost to include price times net flow of electricity into the region, part of the high total system cost for unmanaged charging with 5 million PEVs (shown in Figure 4 and Table 4) is driven by the high imports during spikes of California regional market prices near or at the price ceiling. The high system cost with unmanaged charging shows that the system reaches a saturation point close to 5 million PEVs and that, without the management of PEV charging to avoid peak times and prices, added generation or transmission line capacity or other load management resources are needed to avoid unserved loads.

4.3. Renewable Curtailment and Renewable Generation

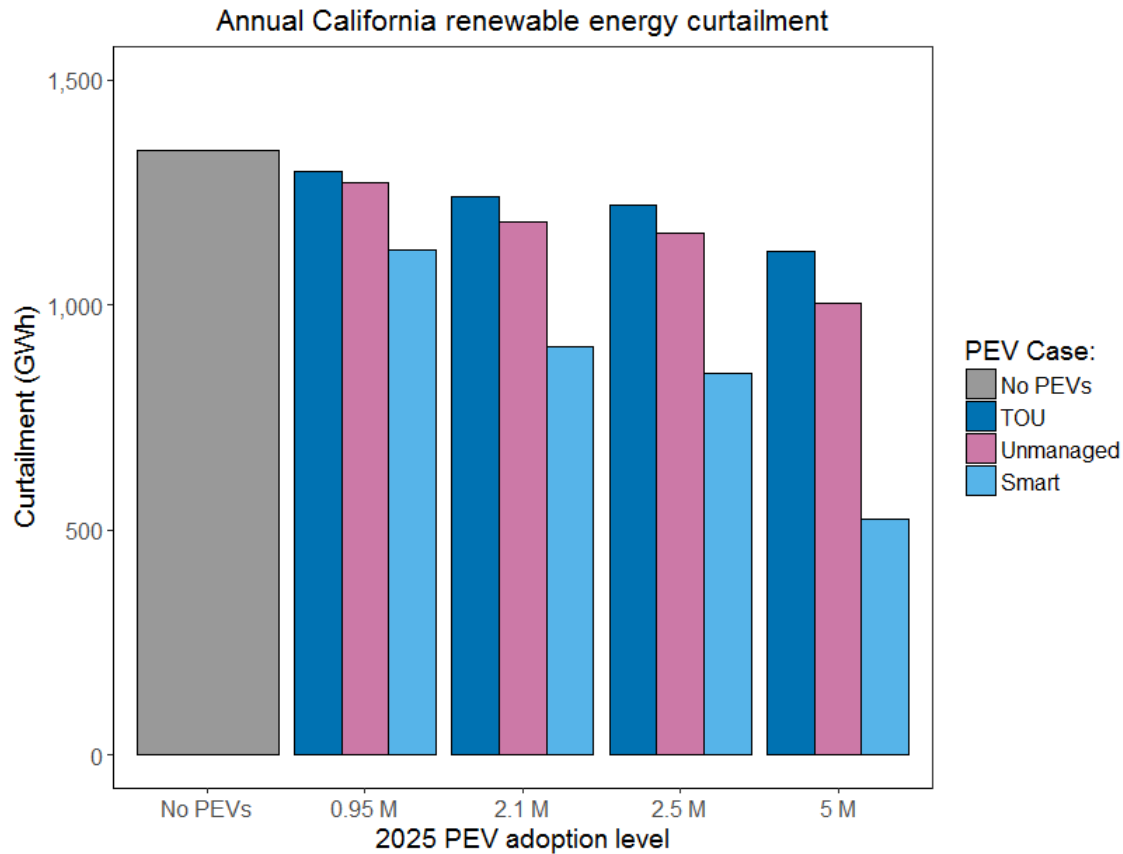


Figure 7: Annual California renewable energy curtailment.

Smart charging shifts load to times with excess RE when power is priced at or below zero (Figure 4). This operational flexibility allows the grid to extract more value from the RE plants that have already been built [25]. Compared with unmanaged charging, smart

charging lowers annual curtailment by an additional 148 GWh or 12% (with 0.95 million PEVs) to 478 GWh or 48% (with 5 million PEVs) (Figure 6). Lowering curtailment can increase investor confidence in developing future RE projects and enable emissions reductions [71]. TOU charging actually results in more curtailment than does unmanaged charging because the RE generation coincides less with overnight PEV load (Figure 4).

RE curtailment is highest in Spring, especially in the month of May, and smart charging reduces that challenge significantly. For example, in the 2.5 million PEV scenario, smart charging reduces RE curtailment in May to 3.3% of solar and wind generation compared with 4.9% in the case with no PEVs (Figure 7). While annual RE curtailment even with unmanaged charging is only 1.3% (0.95 million PEVs) to 1.0% (5 million PEVs) of RE generation, with future RE targets higher than 50% RPS, smart charging could play a significant role in reducing curtailment and thus overall system costs.

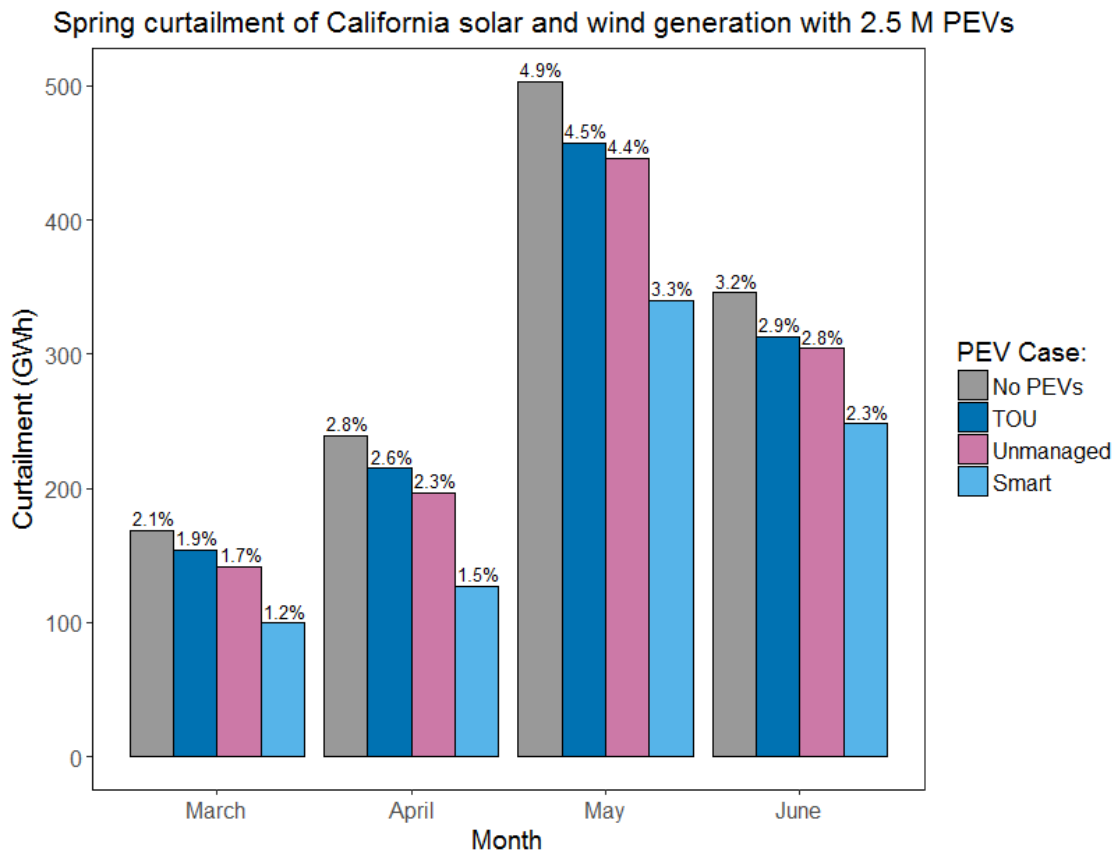


Figure 8: RE curtailment during spring months.

5. Conclusion

As illustrated in Figure 2, this study unifies 1) the BEAM model, which produces realistic PEV charging simulations incorporating driver behavior, mobility patterns, and detailed charging infrastructure constraints, with 2) PLEXOS, which optimizes the power system dispatch with the addition of PEVs to estimate transmission-level impacts of unmanaged

and managed PEVs. We evaluate the system cost and RE curtailment impacts of the addition of 0.95 million (4% of California's current vehicle stock) to 5 million (20% of California's vehicle stock) PEVs under unmanaged, smart, and TOU charging strategies on the California power system with the assumption that the state meets its 50% RPS mandate.

5.1. Key Findings

We find that integrating PEVs in an unmanaged charging scenario, compared to TOU and smart charging, has the following grid impacts for California in terms of total system cost and RE:

5.1.1. System Costs

- When PEVs are added to the grid, the charging strategy employed affects how much grid operating costs increase. Smart charging avoids 47% (with 0.95 million PEVs) to 51% (with 5 million PEVs) of the California system costs increases from unmanaged PEV charging. These costs reflect the wholesale operating costs to generate energy and do not include capital costs, transmission and distribution costs, and any other incidentals that comprise the full cost of producing and delivering electricity, or of retail electricity rates for customers.
- About 80% of these benefits can be gained through TOU charging without the implementation cost of smart charging controls and administration; 34% (with 0.95 million PEVs) to 42% (with 5 million PEVs) of system cost increases can be averted if PEVs already plugged in at home only charge overnight based on current TOU off-peak rate schedules.
- Smart charging has the potential to provide value (by avoiding system operating costs) of about \$90 to \$140/PEV per year compared to unmanaged charging. TOU has the potential to provide value of about \$60 to \$120/PEV per year.
- The benefits of both managed charging strategies are non-linearly related to PEV adoption, and the benefits increase as the power system approaches its generation and transmission capacity limits. If 5 million PEVs participated in smart or overnight TOU charging, capital costs of new generators or transmission could be deferred without leaving load unserved during peak hours of the year.

5.1.2. RE Curtailment

- Among the PEV charging strategies we consider, smart charging reduces California's RE curtailment the most—by an additional 12% (0.95 million PEVs) to 48% (5 million PEVs), relative to unmanaged charging.
- In contrast, nighttime TOU charging increases curtailment relative to unmanaged charging because of a load mismatch with times of high RE generation. With smart charging, the ability of PEVs to reduce RE curtailment is limited by the number of multi-hour, midday charging opportunities without queues at workplace or public chargers.

These grid impacts are specific to the California system and will also ultimately depend on the evolution of the generation mix, curtailment-reduction policies (such as better

coordination with neighboring balancing areas [82]), distributed energy resources (such as other “smart” loads), and flexible supply-side resources (such as stationary battery storage). Nonetheless, most regions with aggressive PEV adoption can benefit from smart or TOU charging strategies to avoid operating and capital costs by reducing peak loads, provided that they overcome any challenges of deploying managed charging program successfully.

5.2. Remaining Research Gaps

There are many areas remaining for further research on the impacts of managed charging on the grid, including:

- Testing different PEV adoption forecasts and different PEV fleet composition (e.g. vehicles with longer range).
- Testing different charging infrastructure scenarios, including the emphasis on fast versus slow charging, and added workplace charging infrastructure.
- Testing more accurate estimation of charging power constraints of the varying available charging infrastructure.
- Using California and/or National Household Travel Survey data to scale PEV charging demand and flexibility in a manner that reflects regional variations in mobility and charging infrastructure.
- Finding correlations between charging demand and mobility profiles (i.e. daily VMT) and including these relationships when scaling demand.
- Simulating the participation of aggregated PEV fleets in other grid services such as regulation and load-following through vehicle-to-grid.
- Testing different renewable generation mixes.
- Testing the impact of competing sources of grid flexibility including increased storage and demand response, varied curtailment assumptions, and higher net export limits.

Finally, there are also many policy changes happening concurrently in California and WECC, which could impact the conclusions of this study. For example, California is already coordinating with neighboring balancing areas through the Energy Imbalance Market, which could alleviate some of the curtailment problems highlighted here [75]. CAISO may also expand to other parts of WECC, and there may be an increase in DR and load management from other end-uses besides PEVs to cope with curtailment. Lastly, there is a push to move residential electric customers in California to opt-out TOU rates in the next few years [83], which may incentivize load shifting during these curtailment periods, without the use of actively managed PEVs.

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